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Research paper

The role of natural gas in setting electricity prices in Europe

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ABSTRACT

The EU energy and climate policy revolves around enhancing energy security and affordability, while reducing the environmental impacts of energy use. The European energy transition has been at the centre of debate following the post-pandemic surge in power prices in 2021 and the energy crisis following the 2022 Russia-Ukraine war. Understanding the extent to which electricity prices depend on fossil fuel prices (specifically natural gas) is key to guiding the future of energy policy in Europe. To this end, we quantify the role of fossil-fuelled vs. low-carbon electricity generation in setting wholesale electricity prices in each EU-27 country plus Great Britain (GB) and Norway during 2015-2021. We apply econometric analysis and use sub/hourly power system data to estimate the marginal share of each electricity generation type. The results show that fossil fuel-based power plants set electricity prices in Europe at approximately 58% of the time (natural gas 39%) while generating only 34% of electricity (natural gas 18%) a year. The energy transition has made natural gas the main electricity price setter in Europe, with gas determining electricity prices for more than 80% of the hours in 2021 in several countries such as Belgium, GB, Greece, Italy, and the Netherlands. Hence, Europe's electricity markets are highly exposed to the geopolitical risk of gas supply and natural gas price volatility, and the economic risk of currency exchange.

1. Introduction

The unprecedented rise in Europe's energy prices in 2021–22 has raised questions about the success of European energy transitions. EU energy policy has been centred around increasing the share of renewable energy sources (RES) (European Council, 2022) to enhance energy security and reduce end-use energy prices in the Union; the two goals that were challenged by the current energy crisis. Transitioning from energy systems based on fossil fuel to variable renewable energy (VRE), such as wind and solar photovoltaic (PV), has complex impacts on electricity markets. These can be seen, *inter alia*, through the impact of VRE on price volatility (Prokhorov and Dreisbach, 2022); flexibility, balancing, and storage requirements for integrating VRE (Pusceddu et al., 2021); the operation and phase-out of thermal (including nuclear) power plants in the presence of VRE (Tahir et al., 2021); market design for accommodating high shares of VRE (Zappa et al., 2021); and policies for promoting distributed VRE generation and storage (Zakeri et al., 2021). The impact of the renewable energy transition in Europe on the formation of electricity prices is another policy question that is difficult to answer, especially as a quantified share of each electricity generation type in setting electricity prices at the European scale. This paper aims to answer this question.

1.1. Electricity prices and renewable energy

In energy-only markets, a power plant with higher merit (i.e., lower marginal cost of electricity generation) has a higher priority in dispatch and access to the grid compared to a more expensive one. On the other hand, the electricity price is set by the most expensive supply bid accepted in the market, typically from technologies with a relatively

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high marginal cost and located “at the margin”, i.e., at the far-right side of the marginal-cost driven supply-cost curve. As low-cost RES such as wind and solar PV are growing in the power supply mix, more expensive generation plants such as fossil fuels are being pushed outside the supply mix or further at the margin – a phenomenon known as the “merit order” effect (Kolb et al., 2020).

The impact of the renewable energy transition on the dynamics of electricity prices has been widely studied in the past. The diverse merit order effect of wind and solar power in Denmark and Germany is studied in Tselika (2022); the role of VRE in electricity price formation is shown in Maciejowska (2020); and the impact of VRE on price volatility in North-West Europe is analysed by Gugler and Haxhimusa (2019).

Previous work has considered the concept of plants at the margin (or marginal plants) in different countries. Germeshausen and Wölfing (2020) explore the impact of lignite on marginal prices in Germany between 2015–2017. They apply a combination of quantity- and price-based approaches to estimate the time of year a power plant can be at the margin. Staffell (2017) measures the progress and implications of decarbonising the British electricity system, considering the marginal generation mix displaced by wind and solar PV without explicitly considering the role of these plants in the electricity price. Blume-Werry et al. (2021) analyse price-setting power plants in the power market by modelling a future Dutch system, emphasizing the role of cross-border interconnectors on final electricity prices. Using long-term simulations, Green and Staffell (2017) infer that thermal power plants will play an important role at the margin due to the need for flexibility and dispatchable generation.

These studies have improved our understanding of the formation of electricity prices and the role of renewable energy transitions. However, the literature on marginal shares has been focused either on one or a few countries, e.g., Portugal (Macedo et al., 2020), Spain Ciarreta et al. (2020), Germany (Kolb et al., 2020), Germany-France 2015-2017 (Germeshausen and Wölfing, 2020) and/or derive their conclusions based on simulations of power systems into the future without analysing historical data, e.g., UK 2020–2040 (Castagneto Gissey et al., 2019), EU 2020 (Blume-Werry et al., 2021) and EU 2030 (Panos and Densing, 2019). Those studies with a focus on historical data at the European scale may offer outdated conclusions, e.g., EU-27 1990–2010 (Haas et al., 2013). As such, there seems to be a need for a systematic analysis of the energy transitions in Europe based on recent historical data in relation to (i) the role of different electricity generation technologies in the formation of electricity prices, and (ii) the implications of this for energy security and affordability in Europe. We aim to contribute to this gap, which is the ongoing policy debate in Europe.

1.2. Contribution of this study

By applying an econometric analysis and looking into the historical power system data of EU27[1] plus Great Britain (GB) and Norway (hereafter, EU27 +) over the past seven years (2015–2021), we analyse the impact of energy transitions in Europe on electricity prices. More specifically, we explore the extent to which each electricity generation type has been responsible for setting electricity prices in each country and in Europe, overall.

Near-zero marginal cost renewables may drive down baseload electricity prices (Hirth, 2018). However, fuel-based electricity generation is likely to continue to set peak prices, and so will profoundly affect the wholesale prices, which are the largest component of electricity costs for European consumers (European Commission, 2023b). Hence, this paper can be useful in assisting policymakers in designing measures to limit the influence of fossil fuel electricity generators on electricity prices. This will become increasingly important as the share of VRE grows, while carbon-intensive generators such as natural gas still provide the required flexibility to integrate VRE into the grid.

The remainder of this work is structured as follows. Section 2 provides background information about European renewable energy policy and progress in the past decade. Section 3 presents our methodology, its novelty and limitations, and data analysis. Section 4 explores the main results, which are discussed in Section 5. Conclusions are presented in Section 6.

2. EU energy policy

The objectives of EU Energy policy to date have been dominated by the 2020 targets, implemented in 2009 (European Commission, 2023a). These targets comprised a 20% target for carbon emission reduction (against 1990 emissions), a 20% target for improving energy efficiency, and a 20% share of RES in final energy demand. The EU achieved the renewable energy target, having increased its share of RES in final energy demand from 8.5% in 2005 to more than 21% by the end of 2020 and for RES-Electricity from 16% to 34% (figures are for EU-27 without GB) (Eurostat, 2023). For the carbon target, the EU is significantly ahead of its objective, having reduced carbon emissions by 24% from 1990 to 2019 (European Commission, 2023c). These achievements underline the significant shift in the energy sector in the last decade driven by EU-level policy. However, EU countries import more than 58% of their energy needs from outside the Union, mainly petroleum products and natural gas (Eurostat, 2022).

Targets for 2030 were proposed in 2016 as part of the Clean Energy for Europeans package (CEP), and fully implemented into legislation by 2019. The carbon target for 2030 was set at 40%, and the Renewables target for “at least” 32% (European Commission, 2018). However, these targets were superseded as part of the EU Green Deal; the proposal for a new EU Climate Law within this package aims to reach carbon neutrality by 2050, increasing the 2030 carbon reduction objective to 55%, RES share up to 39%, and 67% for RES-Electricity (Panarello and Gatto, 2023).

2.1. Share of low-carbon electricity in Europe

Fig. 1 shows the share of fossil fuel-based and low-carbon electricity generation in EU-27+ in 2021. The values are calculated based on the published hourly data on the ENTSO-E platform, subject to data curation and corrections which will be explained in Section 3.3. The European countries have a very diverse set of electricity generation mixes based on their energy resources and low-carbon transition pathways. While in some countries, like France and Norway, the power system is largely carbon-free, other countries such as the Netherlands and Poland are still largely dependent on fossil fuels. The type of fossil fuel used in the countries varies too, from shale oil in Estonia to coal mainly in Germany and Poland, and natural gas mostly in Italy, Greece, Netherlands, and GB. The share of fossil fuel generation varies substantially between European countries from 85% in Poland to less than 1% in Norway. Coal generation has declined in all countries and has been almost eliminated in Spain and GB. At the EU level, fossil fuels account for 34% of electricity generation, and the rest comes from low-carbon generation.

2.2. Fossil fuels and electricity prices in Europe

The prices of fossil fuels have a substantial role in determining the market price of electricity in Europe. This is because of the market

[1] In this paper, EU-27 refers to the EU Member States after Brexit, abbreviated as AT: Austria, BE: Belgium, BG: Bulgaria, CY: Cyprus, CZ: Czech Republic, DE: Germany, DK: Denmark, EE: Estonia, ES: Spain, FI: Finland, FR: France, GR: Greece, HR: Croatia, HU: Hungary, IE: Ireland, IT: Italy, LT: Lithuania, LU: Luxembourg, LV: Latvia, MA: Malta, NL: Netherlands, PL: Poland, PT: Portugal, RO: Romania, SE: Sweden, SI: Slovenia, SK: Slovakia. For hourly data analysis, three countries are excluded due to lack of data or their island situation, namely, LU, CY, and MA.

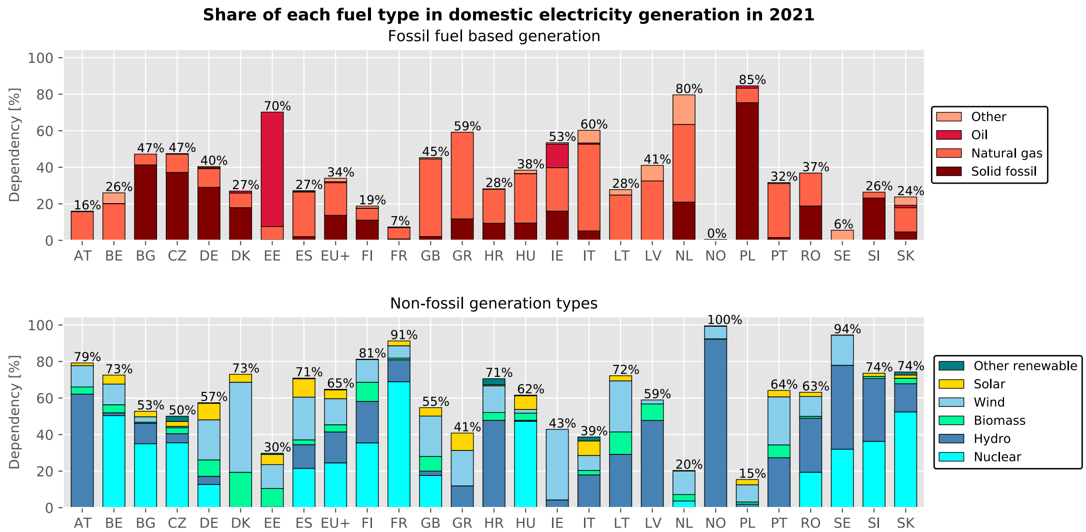

Fig. 1. Share of each generation type in the electricity generation mix of European countries in 2021.
Data from ENTSO-E (2022), data curation and visualization by the authors.

design that incentivizes pricing based on the short-term marginal costs of production, which is traditionally dominated by fuel costs. In Europe, natural gas and coal are the most dominant fossil fuels used for electricity generation (see Fig. 1). Aside from the market prices of fossil fuels, the relative competitiveness of these fuels is affected by the carbon emission price.

European countries have historically imported most natural gas by pipeline from the North Sea or Russia. Since storing and transporting gas is more expensive than oil or coal, natural gas markets are less liquid and more volatile (Hailemariam and Smyth, 2019). In recent years, especially after the Russian-Ukrainian war, several import terminals for liquified natural gas (LNG) have been developed across Europe. Yet the EU remains highly dependent on pipeline gas from non-member countries (Eser et al., 2019) while struggling with the economic and energy security impacts of energy trade disruptions in the aftermath of the war (Chen et al., 2023).

Coal prices are lower than oil and gas but are also volatile. For example, in 2016, driven by low oil prices, both the price and consumption of coal fell substantially. This was followed by a substantial price rise, which was attributed to the increase in Chinese coal consumption (Reuters, 2023). Since coal has a higher carbon content per unit of energy than natural gas or oil, the coal price is most susceptible to carbon taxes.

Between 2012 and 2017, the carbon price in the EU Emissions Trading System (ETS) remained broadly stable at around €5/tCO_2, and this was too low to influence the competitiveness of coal. However, the price of CO_2 started to grow significantly in 2018 due to the tightening of the supply of emission allowances through the Market Stability Reserve. The carbon price reached 30 €/tCO_2 in 2019, the highest level since 2008, over 80 €/tCO_2 by the end of 2021 (the last year of our analysis), and up to 103 €/tCO_2 in March 2023. This increase has had a positive impact on the competitiveness of existing gas power plants compared to coal plants in the long term. Consequently, carbon emissions from the electricity sector in the EU27 declined by 16% in the year following the introduction of the Market Stability Reserve (European Commission, 2023).

3. Methods and data

In the day-ahead electricity markets in Europe, demand and supply bids are received one day ahead of delivery, and the electricity price is derived based on market equilibrium rules for each hour of the actual delivery day (Nord Pool Spot, 2023b). In a marginal price-based market design, the system electricity price is equal to the most expensive accepted supply bid in a specific delivery time, which is the result of crossing supply bids with the electricity demand curve. The electricity generation plants whose bid determines the system price are called “price setter”, or “price maker”, or “plants at the margin”, while those with bids lower than this price are called “price taker” or “infra-marginal” plants. Fig. 2 illustrates how electricity price is typically determined in a specific hour based on crossing electricity demand and supply bids.

Understanding the role of each generation mode in the formation of electricity prices, or the marginal share[2] of that generator, is an important topic in power market analyses for different reasons. Estimating future electricity prices is one of the motivations for determining the marginal share of different power plants, considering the age and the possible retirement of certain plants in the examined period (Lockwood et al., 2020). Knowing which thermal generators are at the margin will help analysts estimate the impact of CO_2 prices on the power prices and profitability of different generators (Dagoumas and Polemis, 2020). Electricity generators estimate future prices and monitor the outcome of the market to apply different bidding strategies to maximize their profits (Motamedi Sedeh and Ostadi, 2020). The system operator follows prices closely to ensure the market is functioning well with affordable prices for consumers and sending the right signal to prospective investors and suppliers. In the following, we briefly review different methods for estimating marginal shares with respect to their limitations and advantages (Section 3.1), the proposed method in this study (Section 3.2), and the data analysis steps (Section 3.3).

3.1. Literature review: Estimating marginal shares

Different modelling methods have been applied to analyse price-maker strategies at the power plant level, including bi-level optimization (Guo et al., 2021), risk-based two-stage stochastic modelling (Sheikhahmadi and Bahramara, 2020), and mixed integer programming (Han and Hug, 2020). At the national level, there are two main groups of approaches in estimating/quantifying the marginal share of generators in power markets.

[2] By “marginal share”, we refer to the share of an electricity generator at the margin in a certain period. For example, a marginal share of 40% for technology A in a year means that technology has been at the margin (setting electricity prices) 40% of hours a year.

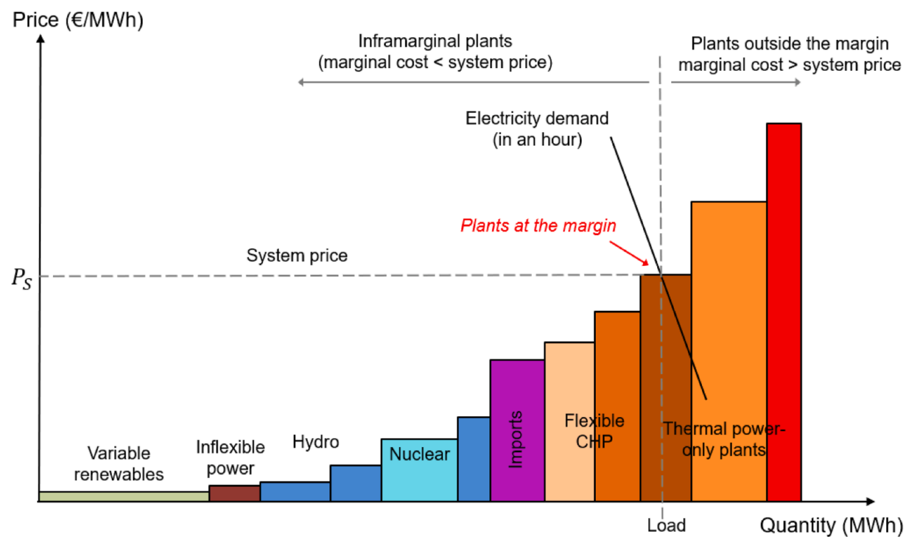

Fig. 2. The schematic of the electricity supply-cost curve showing plants at the margin and inframarginal plants. Note that the order of generation types and the sizes of the blocks are indicative and do not represent the results of this study. (CHP: combined heat and power, inflexible power: electricity surplus from autonomous and CHP plants running following the heat output).

The first approach is based on the application of fundamental operation and dispatch power system models. Using models with a high temporal-spatial resolution and representing power plants in a country or a region, one can estimate the marginal share of each generation type ex-ante, i.e., by back-casting from the model output. The literature is rich in this area, with many sophisticated models analysing future scenarios mainly relying on optimization algorithms and applying open or black-box computer software packages (e.g., Maeder et al. (2021), Jimenez-Navarro et al. (2020), Zakeri et al. (2018) and Golombek et al. (2022)). The advantage of such model-based analyses of marginality is the detail, sometimes at the individual plant level, and the flexibility to represent different states of the power system. Some examples of applying models for analysing marginal shares ex-ante can be found in Blume-Werry et al. (2021). The study calculates marginal shares of different power generation modes, including cross-border power exchange, in many European countries for the modelled year 2020. In another example, Härtel and Korpås (2021) examine the role of cross-sectoral demand bidding and RESs in electricity price formation using a model-based analysis. They quantify the price-setting share of both consumers and producers within a region as opposed to the role of power exchange.

The drawback of using power system models for analysing marginality relates to two aspects. From the process perspective, building a complex model requires adequate modelling skills and a sophisticated tool (Gilbert et al., 2018), relies on many assumptions and modelling judgements (e.g., related to future carbon price, energy demand, and technology/fuel cost) (Chang et al., 2021) , may be biased by the model structure (Ruhnau et al., 2022), and if not validated remains at the theoretical level (Pfenninger et al., 2018). Moreover, concerning the outcome of such models, the calculated marginal shares are ex-ante, i.e., they do not reflect what may happen during the market operation in real life, e.g., loss of a large power plant or interconnector, forecast errors in load and VRE, etc.

The second group of approaches is based on applying econometric and statistical methods to analyse the outcome of a given electricity market for estimating the marginal shares ex-post. These approaches are not typically based on plant-level data but use time series of the market data, e.g., load, generation, and prices, at the national level or for a pricing area. There exist many examples of this approach for analysing the merit order effect, e.g., on the formation of prices (Macedo et al., 2020), the generation of certain power plants (Nolting and Praktiknjo, 2020), the impact of the carbon price on electricity prices (Dagoumas and Polemis, 2020), the role of power exchange in the formation of prices (Keles et al., 2020), and the market power (Chen et al., 2018). Germeshausen and Wölfing (2020) offer a good example for the analysis of marginal shares. They quantify the marginal share of lignite power plants in Germany, by analysing equilibrium prices and quantities. Their method is a combination of two different dimensions based on (i) quantities, e.g., available capacities and demand, and (ii) observed prices resulting from the intersection of supply and demand. The advantage of such statistical approaches lies in their simplicity, better availability of data, reproducibility, and more importantly, the inclusion of past events and actual market clearance information in calculated marginal shares. The limitation of such approaches is the dependence on granular data, which most often requires treating the power market at an aggregate level, e.g., considering all gas generators under one umbrella, which may neglect technological constraints at the plant level.

There are a few studies based on a hybrid approach, e.g., applying econometric analysis to validate the results of a power system model-based analysis or vice versa. For example, Bublitz et al. (2017) examine the role of different price drivers in the decline of electricity prices in Europe. They apply an agent-based power system model coupled with regression analysis to verify model results by comparing both methods. Our approach fits in the second group of the reviewed methods and is explained in more detail in the following Section.

3.2. A price-generation differential method for estimating marginal shares

We apply a simple but robust regression analysis based on the relationship between marginal electricity generation and prices. This method is useful for calculating the share of hours each year in which different types of generators are at the margin.

The balance between generation and demand for electricity in a power market can be shown by Eq. (1), in which L_t is load in each time slice (t) in a year (Y); G_t is generation; and I_t and E_t are import and export of electricity at each time.

$$L_t \leq G_t + I_t - E_t \qquad \forall t \in Y \tag{1}$$

In each time slice (t), generators whose bid is accepted generate electricity. The electricity generation of these generators can be divided into two main parts: (i) generation from plants with a marginal cost lower than the system price at a certain time $G_{l,t}$ (i.e., inframarginal plants) and (ii) generators at the margin $G_{m,t}$, whose bid sets the market price (see Eq. (2)).

$$G_t = \sum_{l \in L} G_{l,t} + \sum_{m \in M} G_{m,t} \qquad \forall t \in Y \tag{2}$$

However, as shown in Fig. 2, the electricity price (P) in each time slice (t) is derived based on the bidding price of a generator at the margin (G_m). Generators at the margin can set and change the electricity price by their marginal generation. Hence, if changing the electricity generation of a generator between two consecutive time slices will drive the change in the electricity price, this generator is likely at the margin. Let us give an example: if generator type A is generating constantly 1000 MWh/h in 24 h a day and the prices in these hours vary significantly, this generator is not likely to set electricity prices nor following the load. But if generator B is changing its generation each hour, and when it increases its generation prices go higher and vice versa, it can be concluded that (i) this generator is following the load and/or (ii) this generator has an impact on power prices. Generator type B is likely a plant at the margin. Eq. (3a) shows this relationship between the change in the electricity price in each hour and the marginal generation of a plant at the margin at that hour.

$$\Delta P_t = f\left(\Delta G_{m,t}\right) \qquad \forall t \in Y \tag{3a}$$

Assuming a linear regression, we derive Eq. (3b) for calculating the marginal share (α) for each generation type as the slope of the line that represents changes in prices relative to changes in generation (β is the intercept in this equation):

$$\Delta P_t = \propto \Delta G_{m,t} + \beta \tag{3b}$$

$$where: \Delta G_{m,t} = G_{m,t2} - G_{m,t1} \Delta P_t = P_{t2} - P_{t1}, \quad \forall t_1, t_2 \in Y, t_2 = t_1 + 1$$

As the generation of different plants depends on their total installed capacity and overall availability, the marginal generation of each generator (g) needs to be normalized by the average generation of the respective generation type in a year. Eq. (4) shows how normalized generation ($G_{g,n}$) is calculated.

$$G_{g,n} = \frac{\sum_{t=1}^{8760} G_{g,t}}{8760} \qquad \forall g \in G \tag{4}$$

Therefore, the marginal share of a certain generator (α_g) can be derived as the linear relationship between change in electricity prices (ΔP) and normalized change in generation of that generator as expressed in Eq. (5).

$$\alpha_g \sim \frac{(P_{t2} - P_{t1})}{\left(G_{g,t2} - G_{g,t1}\right)/G_{g,n}} \qquad \forall t_1, t_2 \in Y;\ t_2 = t_1 + 1;\ g \in G \tag{5}$$

Using Eq. (5), the marginal share (α) for each type of generator in each year is calculated as the ratio between the difference in a technology's output and the *hourly* difference[3] of electricity prices. In other words, this is the amount that the electricity price can change by varying a technology's output from one hour to the next. Fig. 3 shows this Ordinary Least Squares (OLS) regression analysis for GB in Feb 2019. The change in electricity prices is mostly correlated with changes in the generation of gas fuelled plants, nuclear with a minor impact while solar generation is found to have negative correlation with prices. The results of the linear regression model in Fig. 3 show that the model does not capture the variation in the data very well (e.g., $R^2 = 0.21$ for natural gas), but the model is significant, i.e., the relationship between the predictor and response has been modelled very well (e.g., p-value $= 0.0001 < 0.05$ for natural gas). Moreover, the size of the confidence interval (0.05–0.95) around the regression line shows a relatively representative model (e.g., see the translucent bands for natural gas and coal in Fig. 3 (right)).

The results of the regression analysis, i.e., dependency of electricity prices on the marginal generation of different generators, can be normalized and presented as percentages for the examined time horizon, e.g., a year (8760 h). It should be noted that the regression analysis proposed here is not to determine which generation type is at the margin in a specific hour. This method is suitable to approximate the percentage of time in a certain period, e.g., a year (8760 h), that a generation type could have been at the margin. Therefore, the results should be interpreted as aggregated indicators showing the trends and not for predicting the behaviour of a specific generation type or their pricing strategy in a single hour.

3.2.1. *Strengths and limitations of the proposed method*

The proposed method in this study enhances previous panel data methods reviewed in the literature in two ways: by employing a regression analysis using (i) one single predictor that removes the risk of interdependency of predictors and (ii) based on normalized values (instead of absolute changes) to put the differences in a uniform scale. We explain this further here. Ref. Germeshausen and Wölfing (2020) estimates marginal shares by a hybrid indicator based on both electricity demand and prices. Electricity prices are a function of supply-side-driven factors such as power plant availability and techno-economic characteristics of such plants, such as ramp up/down, marginal cost, etc. Electricity prices depend on electricity demand as well, being relatively higher at peak demand hours. Therefore, estimating marginal shares based on both price and demand may skew the regression towards peak demand hours as one dimension used as the predictor of the analysis, i.e., price, is dependent on the other dimension, i.e., demand. Moreover, unlike other methods in the literature, such as Keles et al. (2020) and Chen et al. (2018), we make our analysis based on the relationship between *normalized* changes in generation. We believe this is important as the absolute change of the output of a generation type can be large from one hour to another, implying that this generator is determining the price change, but the change in generation output may be a small fraction of the total output of that generation type. For example, a power generation type (A) may change the output by 100 MWh between two consecutive hours corresponding to a certain price change. If the total generation of that plant type in the examined period would be 10,000 MWh, the change in the power output is only 1% of the total generation. This is different from another power plant type (B) that changes the output by the same 100 MWh, but this amount is 80% of the total output of that plant type. In this example, the generation type B exhibits much more flexibility in load following and it is more likely that this plant would be at the margin, compared to type A.

Estimating marginal shares of different electricity generators using national-level data has several limitations. Treating different generation modes only by their fuel type in an aggregated way does not capture technical differences that may lead to different pricing strategies by generators. For example, there are different gas-fuelled power plants (namely combined- and open-cycle gas turbines, and steam turbines) with different technical and operational characteristics (efficiencies, ramping rates, minimum load, etc.), which may result in different bidding strategies. But all these plant types are grouped as "natural gas generation" in national statistics and in this study. Our approach can, however, reduce this impact to some extent. We normalize the generation data before estimating the marginal share to capture some technical differences between various plant types, by attributing the price change to a fraction of a generation type, e.g., gas turbines, and not to the total generation, which may include less flexible generation types, e.g., steam

[3] A first difference is here defined as a change from an hour to the next. Most electricity markets in Europe run on an hourly basis, while the UK market runs every half-hour. For consistency, we therefore focus on hourly changes.

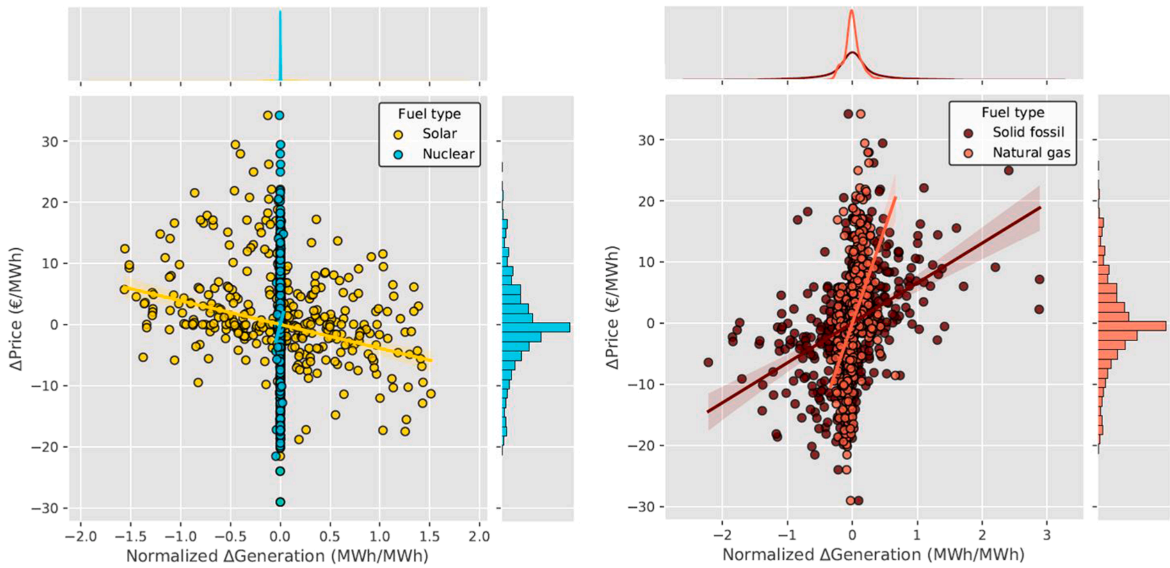

Fig. 3. Relationship between variation in hourly electricity prices and normalized change in the generation of (a) solar and nuclear (left) and (b) natural gas and coal (right) in one month (Feb 2019) in GB. The change in generation is normalized by dividing by annual average generation of each generation type.

turbine gas power plants.

Even power plants of the same type may have different sizes, ages, capacity factors, and consequently different (short-term) marginal costs, which would result in a different pricing strategy. Such plant-level specificities are overlooked in aggregated methods as introduced here, and that is a limitation. In addition to technical characteristics, there may be some operational differences in power plants with the same generation type, which are not captured in this study. For example, some utility companies own a diverse set of power plants, e.g., hydro, gas, coal, etc., and offer electricity or capacity to different marketplaces, e.g., future-forward, day-ahead, intraday, balancing, etc. Hence, the offer of such energy companies to the market is the result of a complex internal optimization of their assets, which may be very different from the offer of a single generator participating in one marketplace.

Some generation types may run combined heat and power (CHP) plants, of which a certain share is must-run CHP[4] with a fixed heat output, i.e., not following electricity demand or price. This is similar to the pricing behaviour of some industry-based power plants, which are used primarily autonomously, but offer their extra available electricity/capacity to the market with little flexibility to vary the output (Helin et al., 2017). The output of such must-run and inflexible thermal power plants exhibits no or little correlation with variations in power prices, even if these plants would be already at the margin. The above-mentioned thermal power plants are typically grouped with flexible plants based on their fuel type in national statistics used in this study. Therefore, our analysis may underestimate the marginal share of thermal power plants, as a fraction of such plants fall into must-run and inflexible generation.

The role of infra-marginal power plants should not be neglected in the formation of electricity prices. These generators are not at the margin, but some can change their output and push another generator with a higher bid to the margin, hence, setting prices indirectly. A prime example of such behaviour is the role of Norwegian, and to a lesser extent Swedish, hydropower plants in the Nordic region. Benefiting from a large reservoir, these plants vary their production significantly during the day to maximize their revenues based on the concept of water value.[5] Therefore, even though the results of our analysis may show that hydropower plants are at the margin, by referring to their generation differential from one hour to another, this may not be completely true. For example, Norwegian hydropower plants shadow-price their offer to the market in off-peak hours based on the price of coal or lignite generation in Germany, pushing these thermal plants to the margin (Blume-Werry et al., 2021). Therefore, our analysis may overestimate the marginal share of hydropower, especially in hydro-dominant countries like Norway.

Considering the above-mentioned points, i.e., the underestimation of the role of must-run thermal power plants at the margin and the overestimation of the role of flexible inframarginal plants such as hydropower, the results of our analysis for the marginal share of fossil fuel types should be interpreted as conservative values compared to their actual shares.

3.3. Data

The provision of open data has contributed to the analysis of energy transitions significantly in recent years (Chang et al., 2021). The data used in this paper is the open, hourly data of EU-27 countries (excluding Malta, Cyprus, and Luxembourg) plus Norway and GB in 2015–2021, obtained from the European Network of Transmission System Operators for Electricity (ENTSO-E), Transparency Platform (ENTSO-E, 2022). The following data curation procedure has been applied to construct time series and conduct regression analysis:

- Hourly electricity day-ahead electricity prices for each country in each year are obtained from ENTSO-E (2022). In the case of countries with more than one price area, the data from the two geographically furthest price areas of that country is averaged for each hour to represent the country. Sub-hourly price data is aggregated to hourly values.

[4] Must-run combined heat and power (CHP) refers to those CHP plants whose main product is process heat or district heat (DH), with electricity being a by-product. These typically small- to medium-sized plants make the main part of their revenues from heat sales, as such, offering their output power with a relatively low price to the market (Helin et al., 2018).

[5] "Water value" defines the bidding strategy of hydropower plants in electricity markets, which is based on the opportunity-cost of releasing one unit of water from the reservoir in a certain hour or keeping it for an hour in the future. This strategy shadow-prices water in the reservoir in competition with the bid of a thermal power plant that could be accepted in the market in the same hour.

Table 1
Average wholesale electricity prices (all expressed in € per MWh) and their compound annual growth rate (CAGR) between 2015 and 2021.

Country	DE	DK	ES	FR	GB	GR	IE	IT	PT
Average price 2021	97	88	112	109	272	116	136	125	112
Average price 2015	32	24	50	38	46	52	39	51	50
CAGR (2015–2021)	20%	24%	14%	19%	34%	14%	23%	16%	14%

- Hourly electricity demand and the actural generation of different generation types for each country in each year is fetched from ENTSO-E (2022). When the data have a large chunk of missing values, these values are possibly corrected based on national and regional electricity market datasets, such as Nord Pool (Nord Pool Spot, 2023a), EPEX Spot (EPEX, 2023), RTE (RTE, 2023), ESOIS (ESOIS, 2023), and OMIE (OMIE, 2023). The annual electricity demand, generation, and share of each generation type is checked with national statistics.

- The installed power capacity of each generation type for each country in each year is obtained from ENTSO-E (2022) and amended and corrected with national statistics if data is missing.

- The hourly data are harmonized to a unique time zone (Central Europe) the winter and summer daylight-saving adjustments are done.

- The data curation and fixing, including filtering out abnormal data, and interpolating the hourly data for missing values is conducted.

After these steps, we apply the regression analysis for each country separately to derive marginal shares. For EU-27, we derive the marginal shares by applying a weighted average of marginal shares relative to the generation of each generator type in all examined countries.

3.3.1. Uncertainties due to data unavailability

There are uncertainties in the data used for the regression analysis that may affect the results. We calculate the marginal shares at the country level. However, a few countries, like Denmark, Sweden, and Norway, have multiple price areas inside the country. This means electricity prices can be different and so the generation type at the margin in each price area. We take the average of the two furthermost price areas in such countries and use national-level generation data as the latter is not typically available per price area. This may over- or underestimate the calculated marginal shares, and we are not able to precisely estimate the effect of such uncertainties. However, since major European countries like Germany and France have one price area, we believe our conclusions for such countries and at the EU level should hold.

The regression analysis in this study is based on two key input parameters: day-ahead electricity market prices and the actual electricity generation by generation type. It should be noted that the latter is reported after the day of delivery, and the data may include the total generation of a plant type in the day ahead, intraday, and balancing markets. This means that a power plant that has been at the margin in the day-ahead market may or may not change its generation output in continuous intraday generation. While we acknowledge that this can affect our results, we are not able to assess the impact of this uncertainty, i.e., whether excluding the operation of a generation type in the intraday market would change its marginal share in our analysis or not, and if yes, by how much. Because the traded volumes in the intraday market are reported as a single value ("buy" or "sell"), we could not find any resources to access the intraday data by generation type. The volume of traded electricity in intraday markets is different among the examined countries. For example, the intraday trade, including both continuous and auction-based, was 34% and 29% of the total trade in GB and Germany, respectively, in 2021, while only 7% in the Nordic countries combined and 10% in France (EPEX-SPOT, 2023). Considering data availability, future research should deduct the generation of each generation type in the intraday market from that of in the day-ahead market to calculate the marginal shares more precisely.

3.4. Analysis of the volatility of electricity prices

In this Section, we analyse hourly wholesale electricity prices (€/MWh) in the examined countries between 2015 and 2021. In 2021, the average prices show the minimum in Denmark with 88 €/MWh, followed by Germany (97) and France (109) (see Table 1). These countries have a relatively high share of renewable energy and cheap baseload, coal in Germany and nuclear in France. The yearly average electricity prices have been growing in most examined countries since 2015. In some power systems, including GB, Denmark, Ireland, and Germany, the mean electricity price has been growing at a significant rate of 34%, 24%, 23%, and 20% per year, respectively. These countries have the highest share of wind power among the examined countries. The average electricity price is also dependent on the weather conditions and overall electricity demand in a year.

Fig. 4 shows the range of electricity prices for each market including the median and the interquartile range (IQR) in each year between 2015 and 2021. The electricity price data were cleaned of outliers, defined as values below 0.5% or above 99.5% of the range. Norway is also added to the comparison, a country with commonly the lowest power prices in Europe. Comparing the results shows that the price volatility and the average price soars in 2021, due to the post-pandemic surge in energy prices in Europe. Germany and Denmark have the lowest prices on a year-to-year comparison, followed by France. The median electricity price has been growing in all examined markets between 2015 and 2021. Moreover, the volatility of prices has been increasing since 2015 in Denmark, Germany, Ireland, and GB, which are the countries with a growing share of VRE generation. In some cases, like Spain and Portugal, the price volatility has slightly decreased in the examined period. In each year, the largest electricity price volatility occurred in France and Ireland. The high electricity price volatility in France is likely due to the high proportion of inflexible nuclear generation used and the widespread use of electric heating that creates demand spikes in winter, while in Ireland this is mainly due to wind variability.

4. Results

We calculate the annual mean shares at the margin for different electricity generation types. These marginal shares, presented as percentages, indicate the fraction of time in a year in which each technology sets the wholesale electricity price in a power system (i.e., the percentage of time a technology has been at the margin).

4.1. Share of each fuel type in setting electricity prices in Europe

We compare the marginal shares of fossil fuel-based electricity generators with non-fossil and electricity imports in EU-27, GB, and Norway in 2021 (see Fig. 5). The results show that in some Nordic countries like Sweden and Norway, hydropower plants set the electricity price nearly all year round. Even though hydropower may be considered a generation mode with near zero marginal costs, but hydropower generation companies typically apply a bidding strategy based on the concept of "water value" (Jahns et al., 2020). This means these power producers offer their generation with a price tag that reflects the value of water in the dam, which is usually based on the opportunity cost of supplying hydropower that could be otherwise replaced with the most expensive thermal generator at the margin (Electric Power Research

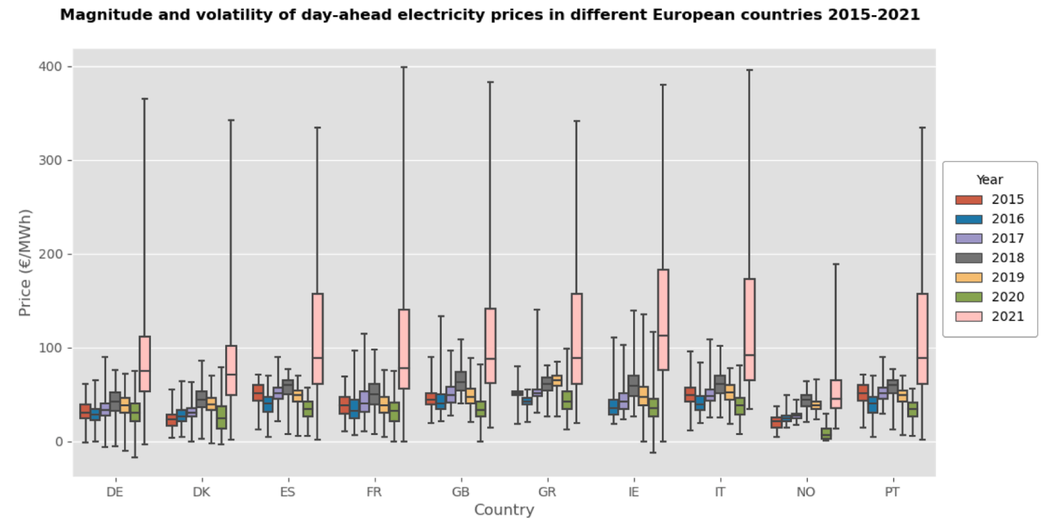

Fig. 4. Volatility in day-ahead electricity prices of the examined European markets in 2015–2021. Boxes show the Interrquartile range (IQR), and whiskers extend from a minimum of 0.5% to a maximum of 99.5% of data in each sample.
Underlying data from ENTSO-E (2022), data curation, analysis, and visualization by the authors.

Institute, 2012).

In many European countries, cross-border electricity imports play a strong role in the determination of electricity prices. Countries like Hungary, Croatia, and Lithuania with electricity imports more than 50% of their annual demand are among those countries highly dependent on the price of imported electricity. The electricity prices in Denmark are also highly dependent on the prices in the neighbouring countries, namely, Norway, Sweden, and Germany, making Denmark price-dependent on these countries 57% of the time in 2021. Domestic electricity generation in Denmark is largely based on wind and solar PV with near-zero marginal cost, as well as CHP mostly running based on heat demand. Hence, the domestic generation is only 43% at the margin in a year.

Nevertheless, fossil fuels determine electricity prices in many countries for most of the hours in 2021. Coal-based generation shapes electricity prices more than 70% of the time in Poland, the Czech Republic, and Bulgaria, and approximately 48% in Germany. Natural gas plays a dominant role in the formation of electricity prices in Belgium, Spain, Italy, Netherlands, and GB.

Overall, fossil fuels set electricity prices in 58% of hours during 2021

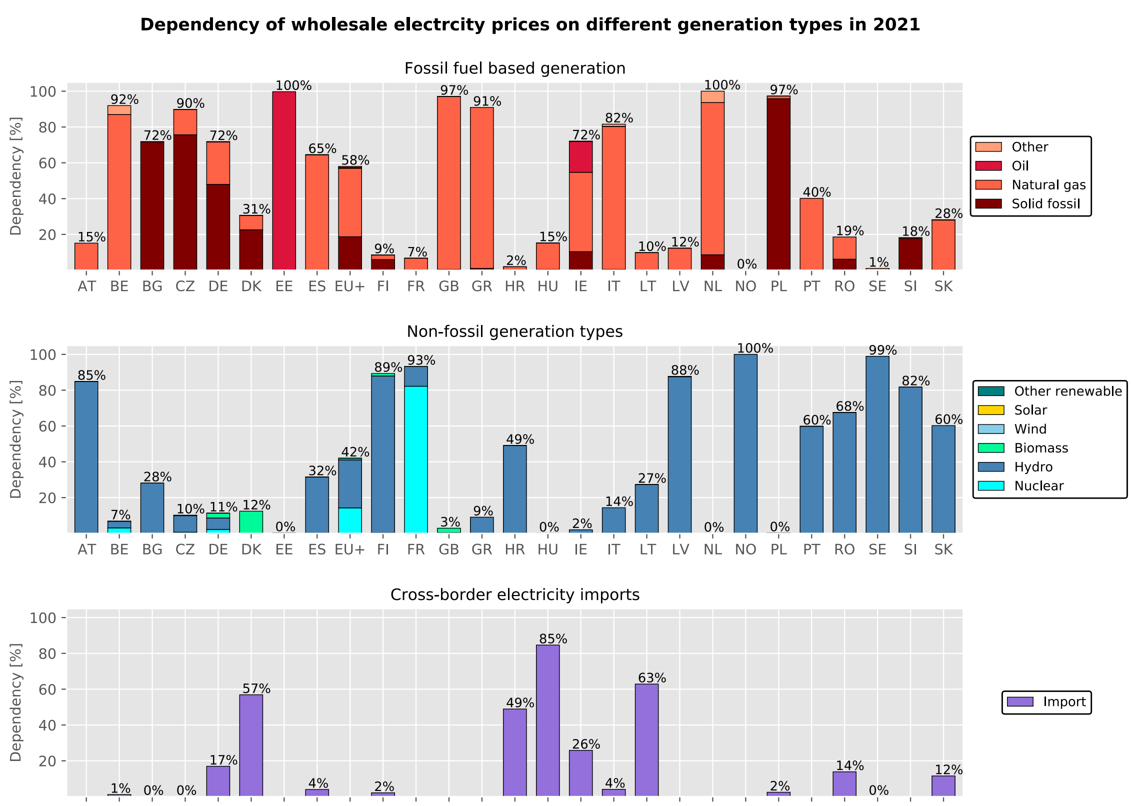

Fig. 5. Marginal shares of different generation types and cross-border electricity imports in different European countries in 2021. (EU^+ = EU27 + GB + Norway). The results for EU^+ are the average of marginal shares of individual countries weighted by their total electricity generation.

Table 2
The marginal share of fossil-fuelled and non-fossil electricity generation in the examined European electricity markets in 2015 vs. 2021.

Year	2015			2021		
Country	Fossil fuel	Non-fossil	Imports	Fossil fuel	Non-fossil	Imports
Germany (DE)	92%	8%	0%	72%	11%	17%
Denmark (DK)	76%	0%	23%	31%	12%	57%
Spain (ES)	62%	36%	2%	65%	32%	4%
France (FR)	3%	97%	0%	7%	93%	0%
Ireland (IE)[a]	87%	2%	11%	72%	2%	26%
Italy (IT)	59%	30%	10%	82%	14%	4%
Greece (GR)	42%	0%	58%	91%	9%	0%
Portugal (PT)	59%	41%	0%	40%	60%	0%
Great Britain (GB)	88%	1%	12%	97%	3%	0%

[a] Values for Ireland are from 2016 instead of 2015 due to the lack of data.

in EU-27 + . This means that even though 66% of electricity generation in Europe was from non-fossil power generation in 2021, these plants set the electricity price in Europe only 42% of the time.

4.1.1. Fossil vs. non-fossil generators at the margin (2015 vs. 2021)

Table 2 compares the share of fossil fuel, low-carbon generation (nuclear and renewables), and electricity imports in setting electricity prices in 2015 versus 2021 in a selection of countries. Germany shows the highest dependency on fossil fuels in setting electricity prices among the examined countries in this analysis. In 2015, fossil fuels were responsible for electricity prices 92% of the time in Germany. This share was reduced to 72% in 2021 due to the increase of renewables. France is the country with the least dependency on fossil fuels when it comes to power prices, only 3% in 2015 with a slight growth to 7% in 2021. Portugal, Spain, and Italy had the highest shares of non-fossil-based electricity prices in 2015 after France, with 41%, 36% and 30%, respectively. The marginal share of non-fossil generators in some countries has significantly declined in 2021, e.g., due to the phase-out of nuclear in Spain, and reduction in hydropower output in Italy due to draught.

The share of electricity imports in setting domestic electricity prices has increased between 2015 and 2021 for most of the examined markets. This shows the success of European electricity market integration. The electricity price in some countries like Denmark is shown to be dependent on imports from neighbouring countries for 57% of the time in 2021, which is higher than any other country in this Table. Ireland is another country with a successful wind integration between 2015 and 2021 and with an increased dependency of electricity prices on cross-border electricity imports, rising from 11% in 2015 to 26% in 2021.

4.2. Trends in marginal generators

Variations in the generator at the margin between 2015 and 2021 are shown in Fig. 6 for nine selected countries. In France, nuclear power generation dominated the marginal price throughout the period. The

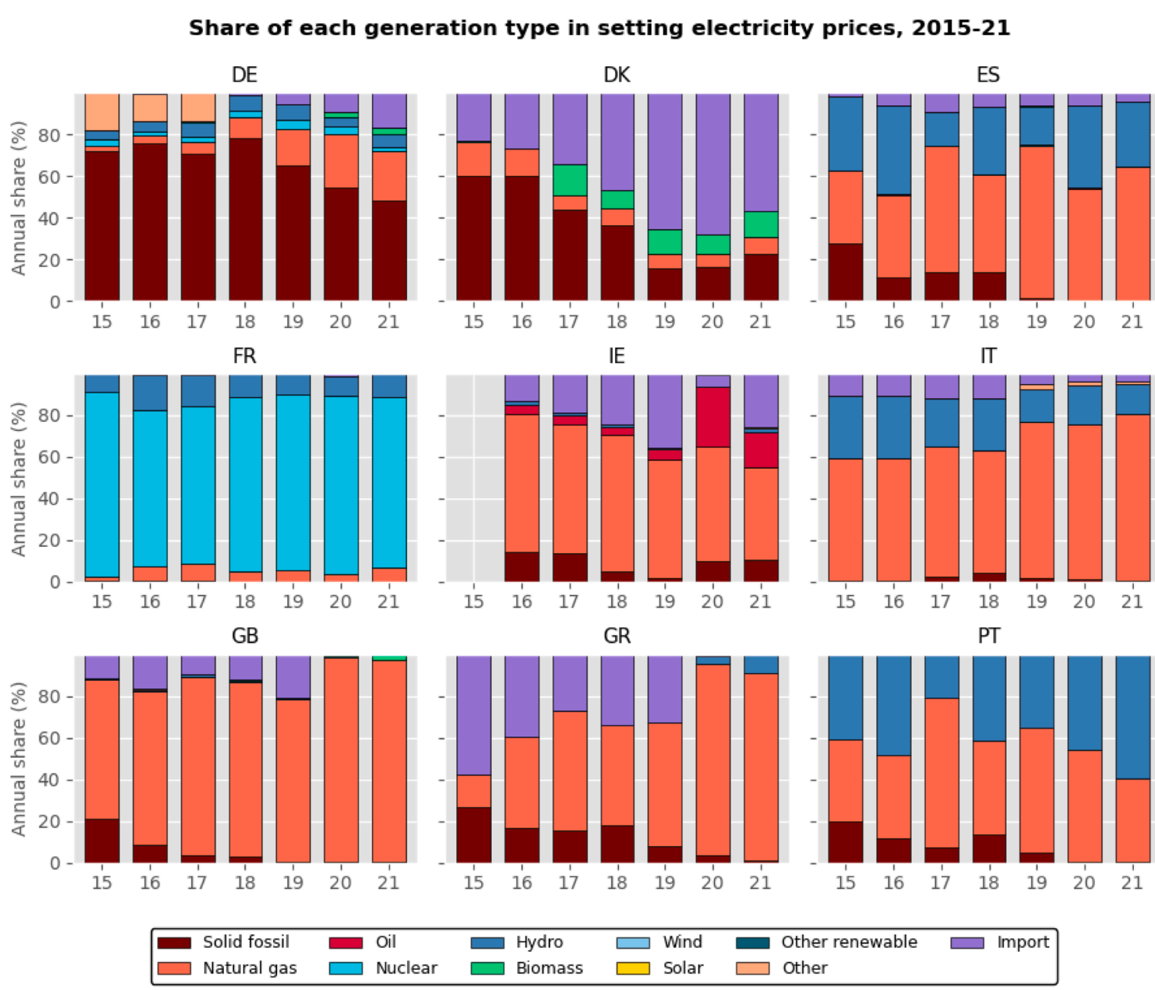

Fig. 6. The share of each electricity generation type in setting electricity prices in selected European countries in 2015–2021 (for Ireland the data are available from 2016).

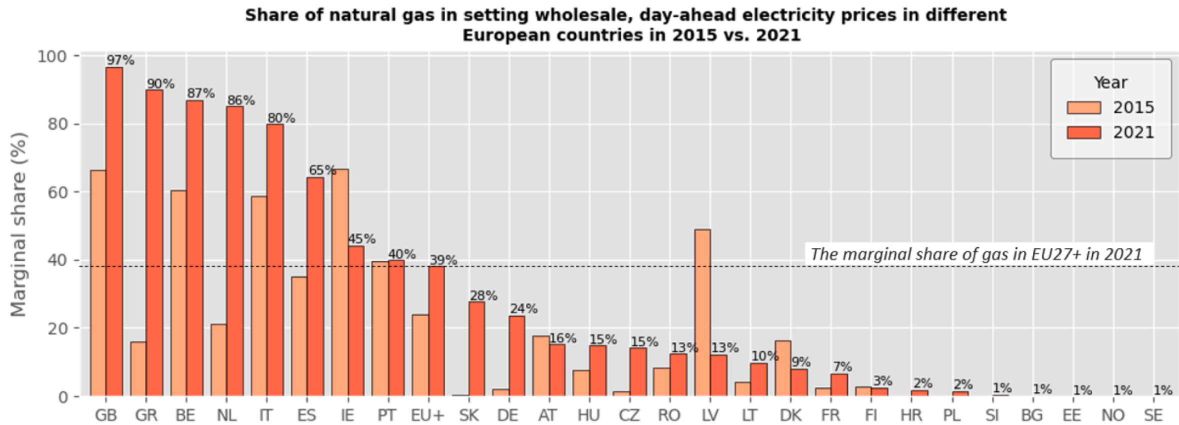

Fig. 7. The role of natural gas electricity generation in setting wholesale day-head electricity prices in different European countries in 2015 vs. 2021 (the data is sorted based on values in 2021). The dashed line shows the marginal share of gas for EU+ (EU27 + GB + Norway).

flexibility of French nuclear power depends on the fuel cycle and hence there might be some flexibility between 70%–100% of the nominal capacity early in the fuel cycle (Jenkins et al., 2018). Coal (including lignite) and gas dominated in the other countries in 2015. In almost all the examined countries, the share of coal power plants in setting electricity prices has declined between 2015 and 2021. The marginal share of coal in GB decreased from 23% in 2012 to 11% in 2017, and almost to zero since 2019. Germany's electricity sector is more coal-intensive, which makes coal power generators the main price setters in the country (75% of the time in 2019 and 48% in 2021).

In Denmark, the role of coal-based electricity generators in forming electricity prices has declined dramatically, from nearly 60% in 2015 to less than 20% in 2019. In Portugal and Greece, the share of coal has steadily declined, but depending on electricity imports (in Greece) and hydropower availability (in Portugal), coal plays a role in setting electricity prices.

Moreover, in most of the examined countries, the marginal share of natural gas has increased in the examined period, with Greece, Italy, Spain, and GB being the countries with the highest dependency of electricity prices on natural gas. Denmark is one of the few countries where natural gas has lost its importance in setting electricity prices over the examined period. This role of gas in setting prices in Denmark has been displaced partly by biomass-based CHP, and to a larger extent by electricity imports from other countries. This situation has been observed in Ireland too, where the role of natural gas in the formation of electricity prices has not increased significantly but imported electricity has replaced the coal-based marginal share.

4.3. Natural gas as a generator at the margin in Europe

The marginal share of natural gas has increased in most of the examined countries. GB, Greece, Belgium, the Netherlands, and Italy have the highest dependency, with gas being the marginal fuel for more than 80% of the time in 2021 (Fig. 7).

From countries with a major increase in VRE between 2015 and 2021, the gas share has only decreased in Denmark and Ireland, both of which have become more dependent on imports as electricity price setter. Latvia is the only other European country with a major reduction in the share of gas between 2015 and 2021. A few countries showed substantially increased dependency on gas as the marginal generator, e. g., Greece from 17% to 90% and the Netherlands from 22% to 86%, between 2015 and 2021. Gas has become the key determinant of the European electricity wholesale price and in 2021 was at the margin almost 39% of the time across Europe overall (the weighted average of the marginal share of gas in all examined countries relative to total electricity generation in each country). This share has been increasing since 2015, which was 25%, as gas has risen to a higher share of the generation mix, and especially the greatest share of flexible, dispatchable capacity. This development was largely due to the decline in the price of natural gas globally and in Europe until 2021, when the price of natural gas soared after the pandemic, as well as the sharp increase in CO_2 price, which strongly favoured gas over coal before the gas crisis in 2022.

Fig. 8 shows the development of the marginal shares of different electricity generation types in EU-27+ between 2015 and 2021. The share in generation is directly calculated by dividing the generation of each plant by the total generation. The marginal shares are the weighted average of marginal shares in European countries relative to generation in each country. The results indicate that while the share of fossil fuels in the generation mix is declining overall, these carbon-intensive generators are still the most influential determinants of electricity prices. More specifically, the share of natural gas power plants in setting electricity prices in Europe has increased from 25% in 2015 to 39% of the time in 2021, which is more than any other technology. This happens while the share of gas in electricity generation was only 18% in 2021.

5. Discussion

5.1. European energy transitions and displacing coal with gas

We find that the EU electricity wholesale price level is most strongly influenced by fossil fuel-based generators and mainly natural gas. The share of gas in determining prices has been increasing since 2015, as gas has risen to both a higher share in the generation mix, and, especially, the greatest share of flexible, dispatchable capacity complementing electricity from VRE. This development was also due to the decline in the price of gas before the post-pandemic price hikes in 2021, and the sharp increase in CO_2 prices, which strongly favoured gas over coal before the start of the war in Ukraine in 2022.

In contrast, the role of coal in setting electricity prices is declining in most of the examined countries by 2021. This is partly due to higher carbon prices in the European ETS starting in 2017. Also, the EU Large Combustion Plants Directive[6] has forced some older coal plants to close since 2015. Fossil fuel plants continue to operate at the margin in many countries, and therefore, set electricity prices for much of the year, a finding that bears out that in other studies (Castagneto Gissey et al., 2018; Staffell, 2017). We have found that the proportion of time that gas plants are the marginal generators has increased, replacing coal power

[6] The EU's Large Combustion Plant Directive (LCPD) required all coal-fired and oil-fired plants whose owners were not willing to fit sulphur-scrubbing equipment to close by the end of 2015.

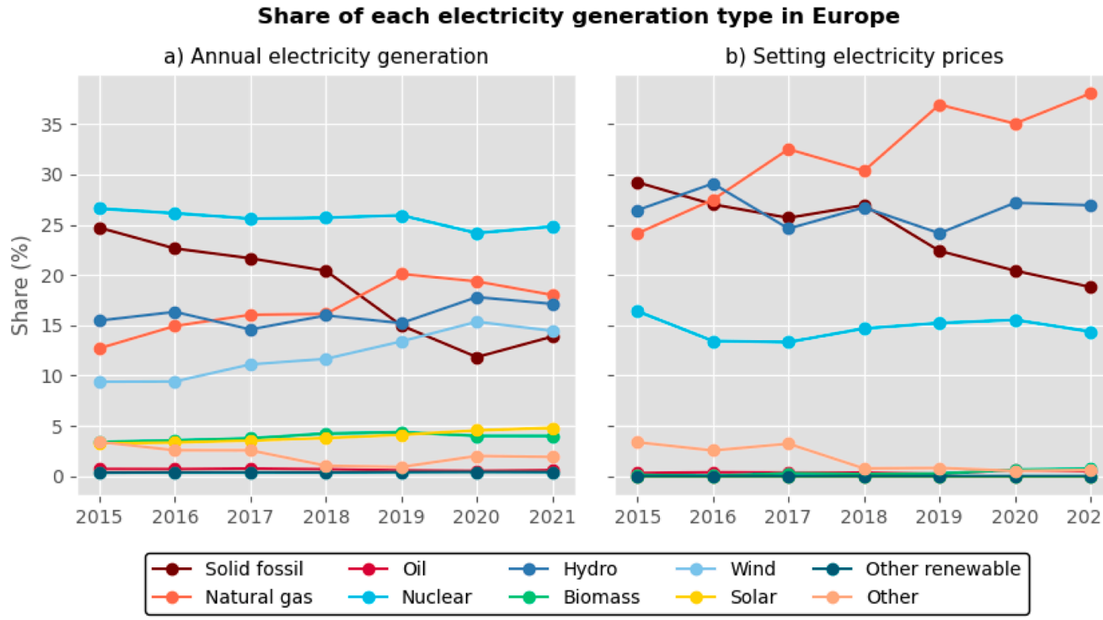

Fig. 8. The share of each generation type in (a) total electricity generation and (b) setting electricity prices in Europe (EU27 + GB + Norway) during 2015–2021.

plants in many countries. The aging coal fleet in many countries is inflexible, which further reduces operational hours in a market with increasing demand for flexibility. We found that coal has continued to dominate marginal costs in a small number of European countries, especially Germany and Poland, which is confirmed by other studies (Wilson and Staffell, 2018).

Since natural gas markets are more localized than global coal markets, this potentially increases energy security concerns for European electricity systems (Sutrisno and Alkemade, 2020). The extensive influence of gas generators on the electricity price therefore makes consumers heavily exposed to several risk factors. A second difference between natural gas and coal is that gas is used for heating in many homes in Europe. If supply were constrained in Europe in winter, since it is unlikely that the supply for heating would be rationed, it would be necessary to either ration gas or electricity to non-residential customers, or to keep non-gas generation capacity in reserve so the electricity system industry could switch to alternative fuels, but at a cost. Similarly, if gas prices rise, as happened in the second half of 2021 and through 2022 in Europe, consumers must pay more for both heating and electricity. This could reduce energy affordability and access for European citizens.

The dark and spark spreads compare power prices to the marginal cost of coal and gas, respectively. These spreads can be used as a measure net revenue and profitability of each fuel type. The gap between the dark and spark spread will indicate which fuel is more profitable for power generation, resulting in fuel switching. For example, following the record high gas prices in Europe in the summer 2021, German gas-fired electricity generation fell, and was surpassed by hard coal generation, which replaced gas at the margin in many hours. Opposite to this trend, in 2023, when gas prices fell again, the spark spread became larger than the dark spread, resulting in coal-to-gas switching in GB and Germany. For example, in March 2023 gas margins moved above coal for the first time in Germany since the beginning of the gas crisis in 2022, with 40% efficiency coal-fired plant margins averaging a premium of €50.5/MWh to 50% efficiency gas since December 2022 (Argus Media, 2023).

5.2. Geopolitical risk of natural gas lock-in

As most EU countries import their gas from outside Europe, by pipeline, the security of supply is affected by regional geopolitics. Geopolitical conflicts between countries that are the import corridors of natural gas to Europe, such as those between Ukraine and Russia, have affected the availability and price of natural gas to EU countries a few times (Dyson and Konstadinides, 2016). More recently, the sanctions and disruptions to the import of gas from Russia in the aftermath of the war in Ukraine have created significant concerns over the impact on prices in the short run (Tollefson, 2022; Erias and Iglesias, 2022). In the long run, as similar energy trends are happening in many countries, demand for natural gas and LNG may rise globally, which will impact the gas price as a global energy commodity (Provornaya et al., 2020).

The risk of dependency on natural gas imports in Europe has been the subject of much debate within the EU. To reduce the current dependency on a small number of gas suppliers, the EU is seeking to find new gas supply routes and diversify supplies. This has made the Union more active in political and economic cooperation with gas exporting regions, e.g., in North Africa and the Middle East (Esily et al., 2022), which requires changed foreign policy in establishing long-term relations and forming new coalitions (Rubino, 2017). Therefore, natural gas interconnectors and LNG infrastructure have become a lever in the policy debate, which makes the construction, completion, and commissioning of such multi-billion-euro projects dependent on the prevailing political environment between the EU and other countries. Nord Stream 2, a subsea gas interconnector between Russia and Germany is a good example of this geopolitical risk, when in 2019, the US pressed companies involved in the construction of the pipeline to stop working on the project by threatening sanctions. Later in the European natural gas price crisis in 2021, it was argued that Russia has reduced gas supply to Europe through other lines as leverage to push the final approval of Nord Stream 2 by the European Commission. Ultimately, the commissioning of the line was withdrawn by the German side as a consequence of the Russia-Ukraine war in 2022 (Delfs et al., 2022).

Reducing dependency on fossil fuel imports was one motivation for the EU energy transition, which aims to enhance energy security by increasing the role of renewable energy (Dyson and Konstadinides, 2016). However, since the European energy transition has replaced coal in large part with natural gas in the power system, this has led to a natural gas lock-in in major power systems in the Union, such as Germany (Brauers et al., 2021), increasing the vulnerability of the European electricity system.

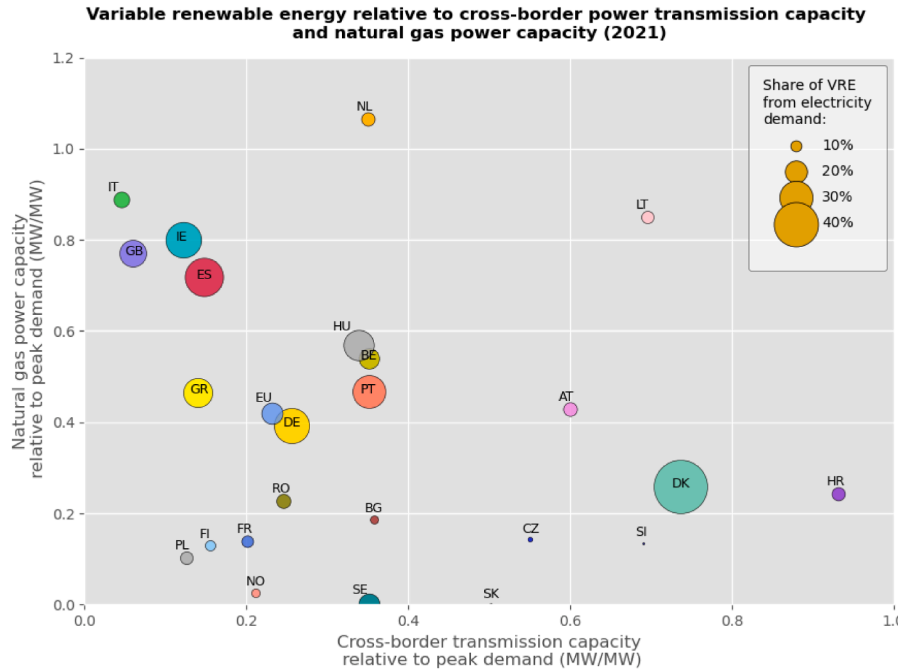

Fig. 9. Relationship between the share of variable renewable energy (VRE), i.e., wind and solar PV, and the cross-border power transmission capacity (horizontal axis) and natural gas power capacity (vertical axis) both normalized by peak electricity demand in each European country. The size of the circles represents the share of VRE relative to annual electricity demand in 2021.

5.3. *Risk of volatility in fossil fuel prices and exchange rates*

Importing natural gas from overseas exposes electricity generation prices to two major risk factors: changes in prices of imported gas and currency exchange rate variations. According to the Office of Gas and Electricity Markets (Ofgem), the volatility in British peak electricity prices is 54% correlated with the variations in the market price of natural gas (Ofgem, 2023). As natural gas prices are cleared based on cross-continental supply–demand imbalances, and partly indexed to the global prices of crude oil, any fluctuation in crude oil prices or transitions in exporting regions influences the natural gas price in European markets as well.

Fluctuations in the currency exchange rate create another risk factor related to the dependency on fossil fuel imports. The volatility of currency exchange rates can influence the electricity price of fossil fuel generators in Europe (Krzemień et al., 2015). For example, it has been shown that the Spanish electricity spot prices are dependent on both the USD/EUR exchange rate and fossil fuel prices in the global markets (Muñoz and Dickey, 2009).

The impact of Brexit on electricity prices in GB is another example (Geske et al., 2020). Mean day-ahead power prices were nearly 18% higher in GB in the year after the EU referendum compared to the previous year. As shown in Castagneto Gissey et al. (2018), the dominant influence was through the exchange rate impact on the cost of inputs to generation linked to the drop in the GBP/EUR and GBP/USD exchange rates, which fell by 15% in the year after the vote. With wholesale costs accounting for over a third of the final electricity bills in GB, the impact of the referendum on exchange rates thereby appears to correspond almost exactly to the increase of 5.7% in retail electricity prices from 2016 to 2017 (National Statistics, 2022), adding about two billion pounds to energy bills in a single year (The Independent, 2023). This depicts the risk of exchange rate fluctuations for countries whose electricity prices widely depend on the exchange rate.

5.4. *Carbon prices and marginal generation*

Carbon emission prices have increased in Europe since 2017. This has increased the marginal cost of carbon-intensive generators, particularly by reducing the competitiveness of coal power plants in recent years, even in countries like Germany where the price of hard coal and lignite are typically low (BloombergNEF, 2023). The subsequent reduction in coal generation across Europe has caused the carbon intensity of electricity generation to reduce substantially between 2017 and 2019. While this trend has contributed to achieving emission and renewable energy targets, the combination of higher zero-marginal-cost VRE in the power system and higher carbon prices has increased the dependency of electricity prices on the cost of carbon emissions from flexible, fossil-based power plants. This is expected to continue as EU carbon prices are predicted to increase to between 80 and 200€/t by 2030 (Carbon Tracker, 2023). Carbon-intensive generation is likely to continue its dominance as a price setter in Europe in the future (Green and Staffell, 2016), even with increased carbon prices, as they remain the major dispatchable and flexible generators.

The carbon emissions from the electricity sector in the EU27 declined by 16% in 2019 compared to 2018 (European Commission, 2023). The impact of higher carbon prices on wholesale electricity prices was partially moderated by declining fossil fuel prices, reduced electricity demand, and the rising share of renewable generation. However, in countries with greater reliance on fossil fuels, electricity prices grew. More notably, the cost of coal-based generation increased in 2019–2020, which together with falling gas prices before 2021 resulted in gas prices falling below coal-to-gas (and even lignite-to-gas) switch price levels in Northwest Europe in 2020 (BloombergNEF, 2023). This resulted in an unprecedented displacement of coal and lignite with natural gas in Germany.

Natural gas is historically considered a "bridge fuel" to phase out coal in energy transitions and provide flexibility for integration of VRE. However, the natural gas lock-in in Europe, with significant investments in gas-fuelled electricity generation, gas networks, and LNG infrastructure taking place in different countries across the continent, poses a risk in achieving EU climate goals such as carbon neutrality by 2050 (Zhang et al., 2016). While the level of carbon emissions from natural gas combustion is relatively low compared to coal and oil, the climate impact of methane leakage from the natural gas supply chain may counter-balance the benefits of gas if not controlled adequately (Hausfather, 2015). This has raised a debate over the taxonomy in the European Commission's decision to label natural gas together with nuclear as "green" investments under some conditions (Clifford, 2022).

5.5. Flexibility requirements of renewable energy transitions

As the share of generation from VRE has increased, price volatility in many European markets has also increased. For example, the number of hours with negative electricity spot prices in Germany broke all records in 2020, whereas GB witnessed price peaks of almost £1500/MWh in early 2021. If VRE generation increases to high levels then these technologies alone will provide generation needs throughout much of the year instead of natural gas, at a very low marginal cost. While historical trends would suggest a need for more rather than less flexible generation, there are other ways to balance supply and demand.

One apparent source of flexibility is strengthening the European internal energy market via cross-border transmission lines, which is also one of the core targets of the EU energy security strategy. Despite a temporal correlation in wind or solar conditions within Europe, the intermittency is less pronounced across a larger spatial area and an interconnected grid (Gils et al., 2017). Consequently, cross-border transmission capacity is estimated to grow significantly within the next decades (ENTSO-E, 2021). Fig. 9 shows that those countries with a high level of interconnectivity (e.g., Denmark) or notable hydropower capacity have been able to integrate higher shares of VRE with low reliance on natural gas. But others like Italy, GB, Ireland, and Spain have kept gas as a flexible generation source.

However, if the imported electricity originates from fossil fuels, the interconnectivity may increase overall carbon emissions, such as the import of coal baseload electricity from Germany to Denmark (Zakeri et al., 2016) or the GB-Europe interconnections with different carbon prices (MacIver et al., 2021).

6. Conclusions

Given substantial efforts to decarbonise European electricity systems, the post-Covid hikes in electricity prices seen across Europe, followed by the natural gas price shocks after the war between Russia and Ukraine in 2022, have raised the question of whether fossil-fuelled generation is still dominating in setting power prices. We analysed hourly electricity generation data by fuel type, electricity prices, and the generation mix in the EU-27, GB, and Norway. Using econometric techniques, we estimated the shares of fossil-fuelled and fossil-free generation in determining European electricity wholesale prices.

We find that the share of carbon-free electricity from renewables has grown during 2015–2021 in most European countries, while fossil-fuelled electricity generation has fallen to 34%. However, carbon-intensive plants were responsible for setting electricity prices 58% of the time in 2021. The increased shares of wind and solar PV have reduced the share of coal as the power price maker, and the role of natural gas as a more flexible and cleaner form of generation has increased in setting electricity prices. The competitiveness of coal has further been reduced due to increasing carbon prices and variable renewable electricity generation with lower marginal costs that have downsized the baseload market. As a result, coal generation has been partially phased out in many countries and replaced by more natural gas. This trend has led to higher dependency on electricity imports in Ireland and Denmark, leading to an increased price dependence on interconnected electricity markets.

The share of natural gas in power generation has increased from 13% in 2015 to 18% in 2021 in Europe. The share of natural gas in determining electricity prices is, however, much higher than its role in electricity generation. Gas-fuelled power plants were at the margin for 39% of the time in 2021 across European electricity markets. Electricity prices in Europe have never been set so often by gas prices during the last decade as they are now. As most natural gas is imported to Europe, this increasing reliance on natural gas as the price setter makes European electricity prices subject to geopolitical risks, international natural gas price volatility, and currency exchange rate fluctuations. In this regard, increased generation from renewables and natural gas has replaced coal and reduced European carbon emissions, but mean electricity prices and volatility have increased during 2015–2021 partly due to the rising cost of gas-based power generation a higher dependency of power prices on natural gas price.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The output results are presented in the supplementary material in an Excel file.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.egyr.2023.09.069.

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